ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

TO: Members of the House Energy and Technology Committee

FROM: Association of Businesses Advocating Tariff Equity

RE: Committee Hearing on House Bill 5476 (Stamas)

DATE: April 29, 2014

Thank you for this opportunity to provide Comments on HB 5476. These Comments cover (1) cost allocation; (2) rate design; (3) amendments to HB 5476; and (4) an outline of other measures needed to provide Michigan with competitive electric rates.

I. COST ALLOCATION

HB 5476 requires the Michigan Public Service Commission ("PSC") to examine the cost allocation and rate design methods used to set retail rates, other than the default methods set forth in MCL 460.11(1), if the new methods would establish rates closer to the cost of service and not require rate increases to primary customers. ABATE supports the cost allocation methodology which allocates production costs on the basis of the average of the four highest coincident peak demands and based upon using 100% class contribution to demand. For transmission, the cost allocation should be based upon the way the Federal Energy Regulatory Commission ("FERC") allocates costs to Michigan utilities, which is based upon the average of the 12 coincident peak demands and the use of 100% demand allocators.

ABATE has consistently petitioned the PSC to adopt such allocation methodologies, and excerpts from ABATE's evidentiary presentation in Consumers Energy Company's last electric general rate case, U-17087, are attached. This testimony demonstrates that cost of service principles require the adoption of new cost allocation methodologies in order to move rates closer to cost of service.

The cost allocation methodologies discussed in the testimony should be applied to all electric utilities and are utilized by many state regulatory commissions around the country. The 100% demand allocators are common but the number of coincident peaks may vary depending on when a utility experiences its peak demands. Michigan's utilities have been summer peaking utilities for decades.

II. RATE DESIGN

ABATE supports a review of rate design but cannot comment further because there is no specific proposal being put forward, but only principles which support new energy-intensive rates designed to encourage industrial customers to locate or maintain their operations in Michigan. Once specific rate design proposals are forthcoming in the context of the proceedings contemplated by HB 5476, ABATE will be in a position to provide specific comments.

III. PROPOSED AMENDMENTS TO HB 5476

A new provision should be added to Section 11(3) of HB 5476 which would require the utilities to publish a second notice to all customers outlining their specific cost allocation and rate design proposals at the same time that they are filed with the PSC. The PSC should also hold a second pre-hearing conference to allow new intervenors to participate in the contested case proceeding.

In order to accommodate the new notice and a second pre-hearing conference, the timeframe in Subsection (4) of HB 5476 should allow the PSC to issue a final order within 270 days instead of 180 days following the filing of the utility proposals. This will allow for a thorough examination of the utility proposals by the PSC Staff and interested parties.

Subsection (8) should be amended so that the re-examination of cost allocation and rate design would apply to all utilities having a minimum of 120,000 retail customers located in the State of Michigan. This would also necessitate a change in Subsection (9), which would replace 1,000,000 retail customers with 120,000 retail customers.

IV. ADDITIONAL ACTIONS

Modifications to the current cost allocation methodologies and the addition of new rate design proposals aimed at encouraging energy-intensive industrial customers to locate or maintain their operations in Michigan are important first steps in helping to make Michigan's electric rates more competitive with surrounding states. Presently, Michigan's retail rates for all electric rate classes are the highest in the Midwest, and in order to attack this problem, there must be fundamental changes that go beyond cost allocation and rate design. These fundamental changes include the items outlined in ABATE's attached white paper entitled "Michigan Electricity Reform Recommendations," and are comprised of a combination of regulatory changes and new laws that would require such things as competitive bidding for major new energy projects, securitization of mandated environmental costs, the examination of each utility's cost structure, and an increase in the ability of customers to purchase all of their requirements from an alternative electric supplier of their choice. All of these additional measures are needed to address Michigan's uncompetitive electric rates.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief	)))))))	Case No. U-17087

Direct Testimony and Exhibits of

James T. Selecky

On behalf of

Association of Businesses Advocating Tariff Equity ("ABATE")

February 20, 2013

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

Project 9683

Therefore, these costs should be allocated based on a cost-causation principle and not an arbitrary kWh allocation.

Results of Consumers' Cost of Service Studies

Q HAVE YOU ANALYZED THE RESULTS OF CONSUMERS' COST OF SERVICE STUDIES AS SUBMITTED IN THIS PROCEEDING?

A Yes. I have analyzed the results of both the 2011 historical year and forecasted test year electric cost of service studies submitted by Consumers. The forecasted test year is a 12-month period ending December 31, 2013. Exhibit AB-1 summarizes the results of Consumers' forecasted test year cost of service study for the major customer classes and the rate classes of the Primary class customers. Just so it is clear, Consumers performs a power supply or production cost of service study and a distribution cost of service study for both the historical and forecasted years. The results shown on Exhibit AB-1 reflect the results of both the production and distribution cost of service studies for the forecasted test year.

Q WHAT DO THE RESULTS OF THE COMPANY'S FORECASTED TEST YEAR COST OF SERVICE STUDY SHOW?

A Exhibit AB-1 shows the results of the Company's cost of service study at present rates and the increase (deficiency) that the customer classes would need to bring their rates to Consumers' requested rate of return.

As the results of the cost of service study show, the Residential class is providing a return below its cost of service. Consumers is requesting a $148.4 million revenue increase and the Residential class would need an increase of $112.6 million to bring its rates to Consumers' requested rate of return. This does not include any

allocation of the rate discounts. The rate discounts are not allocated to the various classes in the cost of service study.

The cost of service study shows that the Primary class should receive a rate decrease of $20.5 million. The actual level of the rate decrease is larger when the General Service Large Industrial Economic Development Primary Rate E-1 ("Rate E-1") is excluded. Rate E-1 receives a discount from the standard tariff rate. In the cost of service study, Rate E-1 is fully allocated all embedded costs. Therefore, the cost of service study indicates that this rate class's discount is $49.0 million. This rate discount is allocated to all rate classes and is not solely borne by the primary class. The cost to serve the various Primary rate classes is shown on page 2 of Exhibit AB-1.

Q WHAT COST ALLOCATION METHOD FOR FIXED PRODUCTION PLANT DID CONSUMERS UTILIZE TO DEVELOP ITS RATES?

A Consumers used the 4 CP method to allocate production fixed costs and the 12 CP to allocate the transmission fixed costs. These methods allocate fixed costs 100% on CP demands.

The Commission has used a 50/25/25 allocation method in Consumers' last rate case to allocate fixed costs. This method allocates these costs 50% on 4 CP demands, 25% on on-peak energy, and 25% on total energy (4 CP 50/25/25).

Q WOULD YOU PLEASE EXPLAIN WHAT IS MEANT BY THE AVERAGE OF 4 CP?

A The 4 CP allocation factor is based on class contributions to Consumers' highest four monthly summer coincident peaks in each of the four summer months, which are June through September. Under this method, the coincident demand, at the time of

each of the four monthly summer peaks, is used to allocate the production fixed costs.

Q DO YOU AGREE THAT THE 4 CP METHOD IS APPROPRIATE FOR ALLOCATING FIXED PRODUCTION COSTS IN CONSUMERS' COST OF SERVICE STUDY?

A Yes.

Q PLEASE EXPLAIN.

A Consumers has been and continues to be a predominantly summer peaking utility. Therefore, the demands which occur during the summer period cause the need to add or purchase capacity.

Q HAVE YOU REVIEWED CONSUMERS' MONTHLY PEAK DEMANDS?

A Yes. Exhibit AB-2 shows Consumers' monthly maximum peak demand in each month for the 10-year period, 2002 through 2011, as reported in FERC Form 1. The data show that the summer peaks have clearly been the dominant peaks over the last 10 years. As previously stated for purposes of this case, the summer months are defined as June through September.

Looking at an average of the four monthly summer peaks over this period indicates that for summer months the highest average monthly peak is 86% of the highest peak demand which occurred in August. It should be noted that a case could be made for using a 3 CP to allocate the production fixed costs, since the average June through August peaks are within 95% of the average maximum August peak.

Also, a review of Consumers' forecasted monthly peaks for the period 2013 through 2017 also indicate a dominance of the summer period. Exhibit AB-2 also shows the monthly forecasted maximum peaks from 2013 through 2017. Consumers is forecasting that the dominant summer peak demands will continue.

Consumers must plan for and provide adequate generation capacity to meet the summer peak loads on its electric system. Therefore, it is the summer peaks that are causing Consumers to acquire generation capacity and the Company to incur additional production fixed costs.

Q HAVE YOU PERFORMED ANY ADDITIONAL ANALYSIS OF CONSUMERS' PEAK DEMANDS?

A Yes. I have reviewed Consumers' hourly peak demands, as reported in FERC Form 713, for 2006 through 2008. These data provides hourly load for each hour for 2006 through 2008. It should be noted that this was the only data that was publicly available.

That data was reviewed to determine how many hourly peaks on Consumers' system were within 10% of the maximum peak that occurred during each hour and in which month did those peaks occur. Exhibit AB-3 shows the results of this analysis.

For the years 2006 through 2008, all hourly peak demands that were within 10% of the maximum system peak occurred in June, July, August or September. The analysis also shows that in 2006, 2007 and 2008 there were 35, 63 and 49 hourly peaks that were within 10% of each year's annual peak. This data indicates that the Consumers is a summer peaking utility and all of the significant peaks occur during the summer months.

Q DO YOU SUPPORT THE USE OF THE 12 CP METHOD TO ALLOCATE TRANSMISSION-FIXED COSTS?

A Yes.

Q WHY ARE YOU SUPPORTING THE ALLOCATION OF THE PRODUCTION-FIXED COSTS ON A 100 PERCENT DEMAND 4 CP AND THE ALLOCATION OF THE TRANSMISSION-FIXED COSTS ON A 100 PERCENT DEMAND 12 CP?

A Although a case could be made for allocating the transmission costs based on a 100 percent demand 4 CP method because of the need to build the transmission system to meet summer peaks, the bulk of the transmission-related costs are allocated to the various classes based on the 12 monthly CP demands.

A review of Consumers' proposed 2013 transmission and energy market administration expenses for 2013, as proposed in Case No. U-17094, indicates that approximately 95% of transmission costs are allocated or assigned to Consumers by the Federal Energy Regulatory Commission ("FERC") based on 12 CP demands. That is, the transmission cost to Consumers and its customers is a function of 12 coincident demands. Since these costs are incurred by Consumers based on 12 CP, it is appropriate to allocate these costs to the various classes based on that same allocator. If the 50/25/25 allocator is used in cost of service to allocate the transmission cost, that will result in certain rate classes subsidizing other rate classes. This is inconsistent with Michigan law.

Exhibit AB-4 shows Consumers proposed transmission and energy market administration expense for 2013 and the level and percent of costs that are incurred as a result of Consumers 12 monthly CPs. As page 2 of Exhibit AB-4 shows 94% of

the transmission expense, which is forecasted to be $321 million is charged to Consumers by FERC based on its 12 CPs.

Q WHICH COST ALLOCATION METHOD DO YOU BELIEVE TO BE MOST APPROPRIATE FOR THIS PROCEEDING?

A The 100 percent demand 4 CP method is now the most appropriate to use for allocating fixed production costs. The use of this method provides a better correlation to cost-causation. The transmission costs should be allocated based on a 100 percent demand 12 CP since that is how Consumers incurs the vast majority of those costs.

Consumers' Cost of Service Study

Q DO YOU HAVE ANY REVISIONS TO CONSUMERS' FORECASTED COST OF SERVICE STUDY?

A Yes. I will only address the cost of service study that employs the forecasted test year and uses CPs to allocate the production and transmission fixed costs. I recommend that this cost of service study should be used to design the rates. The allocation of the customer assistance costs should be adjusted so that the allocation reflects proper cost causation.

Q WOULD YOU PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT TO THE COST OF SERVICE STUDY REGARDING THE ALLOCATION OF THE CUSTOMER ASSISTANCE COSTS?

A In the cost of service study, Consumers allocates the customer assistance costs in Account 908 to the various rate classes based on billed sales, excluding Rate E-1.

Michigan Electricity Reform Recommendations

Michigan needs competitive price electricity to retain jobs, create jobs and re-build our economy. Manufacturing is the building block of the economy. Unfortunately Michigan's electricity rates are the highest in the Midwest and well above the national average where manufactures compete. The increase in Michigan's electricity rates since the 2008 legislation is alarming and out of step with the states that compete for manufacturing. Michigan must do a better job at competing. In order to achieve competitive electricity pricing, Michigan needs:

- "Effective" regulatory oversight which "emulates market competition" to ensure prudent business decisions and drive continuous improvement in efficiency, productivity and cost control measures, and
- Market competition (i.e. Electric Choice) where utilities must compete for our business.

1. Electricity Choice

In 2000, the Michigan legislature enacted the Customer Choice and Electric Reliability Act of 2000. The new law opened up the electrical energy market to competition and provided the opportunity for customers to shop for the lowest cost electrical energy from alternative electric suppliers. "From 2000 to 2004, industrial and commercial electric rates fell by approximately 3 percent and 4 percent respectively in Michigan, while rising by about 13 percent and 10 percent nationwide. The state's average rates for all customers moved below the national average. Just as telling, Michigan's electricity prices, which are typically higher than those of Illinois, Indiana, Ohio and Wisconsin, fell enough to diminish the gap and make the state more competitive with its neighbors." In return for opening up the market to competition, Michigan's major utilities received recovery of approximately $160 million in "net stranded costs" and (under PA 142 of 2000) were allowed to securitize $2.2 billion in assets funded by 15 year bonds paid for by monthly charges on all Michigan rate payers which continue until 2015. From 2004 to 2007 these subsidies to the incumbent utilities undercut the price advantage of their competitors. During this time natural gas prices also began to rise and Michigan's electricity prices started rising once again. However, even though the customers choosing an alternative electric supplier declined during this time, Michigan's rates remained below the national average.

In 2008, the legislature made significant changes to Michigan's energy law with the enactment of PA 295 of 2008 and PA 286 of 2008. PA 286 imposed a 10% cap on participation in Michigan's "electric choice" program established under PA 141 of 2000. Conceptually, there is no reason to need a cap whatsoever. The utilities have been granted the right to full recovery of their "stranded" investments and should be required to compete against other non-utility generators to ensure that generation continues to be cost-efficient. The utilities will continue to provide and profit from their transmission and distribution business (as well as all of the generation business that they win through competition). Additionally, the cap on electricity choice prevents economic development in Michigan by out-of-state energy companies. When customer choice was active under PA 142 of 2000, out-of-state energy companies invested millions of dollars in Michigan and built more than 4,000 MW of new generating capacity in the state. With a cap on electricity choice we have sent a message to these companies not to invest in Michigan.

Opening the electric choice market also buttresses the pillars to a successful energy policy that Governor Snyder has laid out in his energy message - reliability, affordable price, protect the environment and overall adaptability.

Reliability: In a competitive / retail choice market nothing changes regarding the delivery of the electricity. Reliability is maintained by the utilities and transmission companies. For generation, each load serving entity must either own or have under contract enough generation to serve customers and have a reserve. In a competitive market, generation will get built to meet the demand. For instance from 2000-2008 when we had full retail customer choice over 4,000 MW of new generation was built by independent developers in Michigan.

Affordable Price: Retail choice allows more suppliers of energy to compete for customers. Competition between suppliers helps reduce prices offered by suppliers. Competition on the energy supply also forces the utilities to control the cost of their energy supply which helps even those customers who do not choose another supplier.

Protect the environment: The competitive market will drive the development of technology to meet environmental requirements at the lowest cost to consumers! Under the regulated model, the utilities decide what type of generation they want to build.

Adaptability: The competitive market is much quicker to adjust to changing market conditions. Recently when electricity demand dropped in Michigan due to the recession and new environmental regulations were being put in place impacting coal fired generation, a competitive supplier responded and canceled plans to build a coal fired generation facility in Michigan. This change did not cost customers anything! Under the monopoly model it took the utility two years to decide to cancel their plans to build a coal fired generation facility and customers had to pay over $14M to the utility to cover engineering and planning cost.

✓ Amend PA286 to eliminate the 10% cap on participation in Michigan's electric choice program.

2. Securitization of Pollution Control Facilities

New EPA rules, such as the Cross-State Air Pollution Rule, EGU MACT (MAT), Section 316b regulations, and coal combustion by-products or residue rules, require electric utilities to invest billions of dollars in water and pollution control facilities or shut down coal-fired generating plants. Securitization is the process by which a utility, following the issuance of a financing order by the PSC, replaces relatively high-cost debt and equity with lower-cost debt in the form of securitization bonds. If water and pollution control facilities were financed by securitization bonds instead of traditional financing, then the savings to customers receiving generation supply services from the utility are enormous. These environmental control facilities are generation related expenditures not distribution. These savings will benefit the full service customers of the utility (i.e. customers who purchase generation from the utilities). Those customers on Retail Choice who purchase their generation from another supplier will already be paying their supplier for the cost of environmental compliance associated with the generation being used to supply them. For Detroit Edison, the equity savings are the pre-tax return of 9.76% less the yield on AAA corporate bonds of 2.2%, for a net savings of 7.56%. The debt savings are Detroit Edison's borrowing cost of 5.53% less the AAA corporate bond yield of 2.2%, for a net savings of 3.3%. The net savings of financing water and pollution control facilities with securitization bonds in the amount of $1 billion, where the proceeds are used to retire equal amounts of debt and equity, are $903 million. The reduced financing costs will minimize the rate increases associated with the installation of this mandated environmental control equipment. Securitization is a financing tool that the utilities have used before. Consumers and Detroit Edison, in 2000 and 2001, under PA 142 of 2000, issued more than $2 billion in securitization bonds in order to fund a 5% residential rate reduction and pay off certain stranded costs. Recently Consumers Energy Company, in case U-17473, is seeking authority to securitize $454 million related to demolition of some power plants that cannot meet MATS and other environmental regulations and impose a "Coal plant securitization charge". Consumers Energy makes the point that securitization will save customers money, "the proposed securitization of $425.8 million provides a net present value benefit of approximately $133.5 million". "Securitization provides a mechanism for recovering the Company's prudently incurred costs at a lower cost to Consumers Energy's customers than would occur through conventional financing methods" (CE Witness D. Kehoe, p5)

- ✓ Legislation be enacted requiring that Michigan electric utilities utilize securitization bonds to finance all new pollution control equipment required by any rule or regulation adopted by the federal environmental protection agency or the Michigan Department of Environmental Quality.

3. Elimination of Self-implementation of Rate Increases and the use of Projected Cost

Prior to the enactment of PA 286 of 2008, the major utilities filed general rate cases every few years and modest rate increases were approved by the MPSC every couple of years. Since the enactment of the "file and use" provisions, both major utilities have filed general rate cases every 12-14 months and sought interim rate increases 6 months after the date of each filing. The file and use mechanism has clearly resulted in more frequent rates increases and higher costs for ratepayers. The utilities argued that the rate case process was taking too long with no certainty of when a case would be decided. However another change from PA 286 is that the MPSC must make a final ruling in a rate case within 12 months of the utility filing the rate case. This change alone provides timing certainty and there is no need for utilities to self-implement rates which have had no effective regulatory review. The use of a projected test year has also resulted in higher rates. Rates are now being set on projections of utility cost and these projections have been high. There is also no recourse once the utilities rates have been set based on projected cost and actual cost are lower. This has only resulted in the utilities over-earning and customers paying higher rates than needed to recover the utilities actual cost. With the ability of utilities to file a rate case every 12 months (which they are), there is no need to use projected cost. Rates should be set based on the utilities actual cost over the prior 12 months. These costs are easier to verify and result in more accurate rates for all customers. Self-implemented rates and utilizing projected cost have resulted in a process where Michigan rate payers are consistently over-paying for utility service.

- ✓ Amend PA286 to eliminate the utilities ability to self-implement rate increases
- ✓ Amend PA286 to require the use of actual cost from a prior 12 month test period and only make adjustments for known and measurable changes.

4. Establish True Cost of Service Electricity Rates

PA 286 required that electricity rates be based on cost-of-service with the subsidies being paid by one class of customers to another class of customers (rate skewing) be eliminated over a 5 year period. However the Commission has failed to address the rate skewing caused by certain cost allocation methods and believes that a certain amount of cost shifting from residential to manufacturing customers is appropriate.

- ✓ Amend PA286 to require Michigan electric utilities to allocate production costs on a 4CP, 100% demand basis, allocate electrical transmission costs on a 12 CP, 100% demand basis, and eliminate all surcharges and trackers that are charged on a kWh basis and skew rates.

5. Supply Planning and Competitive Bid Process for New Electricity Supply

Methods of electric resource planning with in Michigan have been focused on individual regulated utility franchise territories demand forecast and supply-side projects only (i.e., construction of generation, transmission, and distribution facilities). Even the assessment of supply-side options has been limited to a few major technologies, and cost-benefit analysis of the alternatives was rudimentary. Independent power producers, exempt wholesale generators within the NERC region are not considered. This top-down approach only allows for other key stakeholders and public consultation as a last step, if at all, when plans are virtually complete. Michigan needs a competitive bid supply planning process that makes planning more open to relevant governmental agencies, consumer groups, and others, thus considering the needs and ideas of all parties with a stake in the future of the electric system. For instance, as part of the supply planning process transmission and distribution systems should be reviewed to determine if upgrades to these systems would allow any existing underutilized generation to serve the needs in other areas of the state. If it is determined that new generation capacity is required, this competitive bid supply planning process must not favor or give advantage to native utility companies. Non-utility companies should not be limited to construction only or partial ownership. A large portion of cost savings can come from the efficient operation and maintenance of the generation plant. Additionally, the cost per kW of capacity, the cost per kWh of generation output and the cost of transmission interconnection should be calculated for each generation option along with a weighing of reliability and operational considerations (run-time availability / capacity factor, useful asset life, fuel diversity, etc.). This supply planning process should also require utilities to include a review of utilizing combined heat and power (CHP) which would be installed at or near customer facilities generating electric power and utilizing thermal energy for various combinations of industrial process, space and water heating and cooling. CHP is generally twice as efficient as conventional generation facilities and is made possible at its basic level because of an industrial or commercial business' need for the non-electrical thermal energy output. This represents one significant way by which the state could assist their large customers with managing energy costs.

- ✓ Legislation be enacted requiring that Michigan electric utilities utilize a competitive bid supply planning process which is open to all relevant stakeholders to procure electricity to meet anticipated future demand

6. Establish a Reasonable Transfer Price for Renewable Energy Cost

Act 295 established a renewable portfolio standard which required utilities to serve 10% of their sales with renewable energy as of 2015. Act 295 established two sources of funding for payments made to renewable energy developers. A portion of the money was to come from the surcharges established on a per-meter basis, and the market or "transfer" price was to be included in the Power Supply Cost Recovery (PSCR) expense. The Legislature also sought to cap the RPS expense over a 20 year period and to provide "off ramps" if the expense exceeded certain limits. To the extent that more of the cost is included in the transfer price, then the caps and the off ramps can be evaded. The MPSC developed estimates of the transfer price back in 2008 which are now equal to approximately 75% of the price being paid to renewable energy developers. This is far above the utilities' current avoided cost or the market rate contrary to the Legislative intent. This has resulted in the majority of the renewable generation cost being hidden in the PSCR expense.

- ✓ Public Service Commission establish a transfer price with reference to the locational marginal price in the wholesale market instead of basing it upon a gas-fired combined cycle plant

7. Energy Optimization

Under PA 295, a utility that meets or exceeds the statutory energy optimization goals receives a financial incentive (see excerpt from PA 295 below).
"Sec. 75. An energy optimization plan of a provider whose rates are regulated by the commission may authorize a commensurate financial incentive for the provider for exceeding the energy optimization performance standard. Payment of any financial incentive authorized in the EO plan is subject to the approval of the commission. The total amount of a financial incentive shall not exceed the lesser of the following amounts:
(a) 25% of the net cost reductions experienced by the provider's customers as a result of implementation of the energy optimization plan.
(b) 15% percent of the provider's actual energy efficiency program expenditures for the year"

The total electric & natural gas energy optimization financial incentive bonuses received under PA 295 of 2008 For DTE/MichCon and Consumers Energy for program years 2009-2012 is $42,000,000.

Manufacturers already pay large EO charges. Industrial customers should not have to pay again for utility bonuses. The financial reward should be to the customer who achieved the energy cost savings, not the utility that collected their money and made them apply to get it back for use in their own energy efficiency projects.

A more fundamental issue is that these energy efficiency programs are an inherent conflict with a utilities business goal of selling more energy. The utilities should not be the entity that administers any energy optimization / energy efficiency program. A separate state-wide organization should administer the energy optimization program and be paid a set administrative fee. This organization would then develop a budget and provide EO rate charge recommendations to the MPSC. This structure would not require any expensive incentives.

Lastly, large industrial customers are required to pay volumetric natural gas energy optimization surcharges under PA 195 with no ability to seek an exemption. The electricity energy optimization surcharges are a per-meter charge and industrial customers can seek an opt-out of the charges by establishing a "self-directed" energy optimization program. However the opt-out process is cumbersome and establishes a risk of penalties. Manufacturing customers are both sophisticated and highly motivated to reduce energy consumption and costs and their mandatory participation in these energy optimization programs is unnecessary and burdensome. The program has value for small commercial or residential customers who can benefit from the expertise and rebates provided by the program.

- ✓ Amend PA295 to eliminate the EO financial incentive bonus program
- ✓ Amend PA295 to require a separate state wide independent organization to administer the energy optimization program
- ✓ Amend PA295 to allow an easy, straight-forward opt-out of the energy efficiency programs for industrial / manufacturing customers

8. Revenue Decoupling

Advocates of utility "revenue decoupling" believe it will remove economic incentives that work against energy efficiency. The rate design for regulated utilities rewards utilities for selling more energy, while energy efficiency projects result in decreased energy sales. "Revenue decoupling" breaks – or decouples – the link between the amount of energy sold and the revenue realized by utilities, thereby supposedly removing the economic incentives against energy efficiency. However as noted above:
a) The utilities should not be the administrator of energy efficiency programs, and
b) The new utility rate case timing process established in PA 286 already allows for a timely cost recovery and a timely earnings opportunity for utilities. Thus utilities are able to make adjustments for any lost sales/revenue from energy efficiency efforts as part of their overall utility rate case review. Therefore there is no need for separate decoupling mechanisms.

- ✓ Amend PA295 to eliminate the use of all revenue decoupling mechanisms

9. Generation Efficiency

"Today most coal fired generation facilities converts fossil fuel into electricity at 33% efficiency, throwing away two-thirds of every unit of fuel we burn in cooling towers and smoke stacks. That's the same conversion efficiency we had last year. That's the same efficiency we had in 1980. In fact, you have to go all the way back to 1957 to find a year when the electric sector wasted more energy than it does today.
It's not stagnant because we've hit any fundamental limit. Indeed, studies by the US Department of Energy and Environmental Protection Agency have identified a whopping 200,000 MW of potential (that's 20% of the peak power demand of the US) for proven technologies that either recover waste energy from industrials and/or cogenerate heat and electricity from a single fuel source."
One of the key issues holding back increased generation efficiency is our regulated utility model. Our electric regulatory model pays utilities a return on their capital investment, but compels them to pass along all operating costs to consumers at zero mark-up. This creates a great incentive to build capital-intensive new generation. It isolates electric utilities from the economic principles that drive "normal" businesses, wherein capital and operating cost reductions are a route to greater profits.
Our ability to avoid building costly new generation is not just demand side energy conservation and energy efficiency. It is more importantly tied to improving the efficiency of our existing generation fleet.

- ✓ Improve generation efficiency by establishing (i) a formal evaluation of Michigan's generation fleet operational efficiency and (ii) a regulatory model that requires utilities to improve the operational efficiency (increase generation plant heat rates, increase on-line time, reduce system loses and station loads, improve turn down capability, etc.)

10. Audit of Utility Cost

The monopoly position enjoyed by the utility companies in Michigan and throughout the nation gives them an extraordinary degree of power, both economic and political. Their corporate policies not only control the basic resources of industry and commerce and the livability of our homes and communities, but also determine the shape – and cost – of our future. And the primary institutional check on these policies is the Michigan Public Service Commission, a statutorily-created body established by the legislature to oversee and regulate in the public interest the operations of Michigan's utility industry. The United States Supreme Court has made it clear that in establishing a fair rate of return, the Commission must consider how efficiently and economically utilities are managed:

"The return should be reasonable sufficient to assure confidence in the financial soundness of the utility, and should be adequate, **under efficient and economical management**, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties." Bluefield Water Works and Improvement Co v Public Service Commission, 262 US 679, 67 L Ed, 1176 (Emphasis Added).

- ✓ Legislation be enacted requiring the public service commission to conduct a continuing management efficiency review and to periodically make a determination of whether a utility's operations are being conducted in a prudent and efficient manner, and whether its expenses have been reasonably and prudently incurred. The commission should not assume a utility's failure to earn the authorized rate of return results from inadequate rate increases without being completely satisfied, after a specific investigation, that the utility is operating at an efficient and economical level.

- ✓ Legislation be enacted granting the commission an absolute right of discovery to insure that they will be able to secure the required information and data to determine whether the utility is operating under economical and efficient management.

- ✓ Legislation be enacted requiring that the commission make public its findings with respect to the management efficiency review of a utility's operations and the prudence of its expenses in rate proceedings before the commission.

- ✓ Legislation be enacted requiring the commission to include in the rates paid by ratepayers only the costs associated with any utility decision or conduct, or any utility expenses, which are both reasonably and prudently incurred and result in investment that is used and useful in providing retail utility service.

Funding for a management efficiency review:
(A) New Funding.
The funding for a Utility Management Efficiency Audit could first be included in a budget request made by the Administration in the budget for the MPSC. It would not necessarily be a specific line item, but would logically be included in with other costs of regulating the utilities. Then the budgets go through the appropriation process of the Legislature. Once the Legislature has approved a budget for the MPSC for its regulatory activities, then the state Department in which the MPSC is located (currently LARA) assess that amount against the regulated utilities in proportion to the amount of their intrastate revenues. See Act 299 of 1972, MCL 460.111 et seq. The new state budget begins October 1 of each year.

OR,

(B) Existing Funds.
The funding could come from the MPSC's existing budget for regulation which has already been appropriated by the Legislature and already assessed against the utilities pursuant to MCL 460.111 et seq. Obviously the MPSC would have to find the funds within its existing budget amounts under this alternative.